BEFORE THE PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc. for review and approval of a proposed business combination between SCANA Corporation and Dominion Energy, Inc., as may be required, and for a prudency determination regarding the abandonment of the V.C. Summer Units 2 & 3 Project and associated merger benefits and cost recovery plans

Docket No. 2017-370-E

Direct Testimony of
Scott J. Rubin

on Behalf of
AARP

September 18, 2018

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Introduction

Q. Please state your name and business address.

A. My name is Scott J. Rubin. My business address is 333 Oak Lane, Bloomsburg, PA.

Q. By whom are you employed and in what capacity?

A. I am an independent consultant and an attorney. My practice is limited to matters affecting the public utility industry.

Q. What is the purpose of your testimony in this case?

A. I have been asked by AARP to review the Application (including supporting testimony and exhibits) for approval of what amounts to the acquisition of South Carolina Electric & Gas Company ("SCE&G" or "Company") by Dominion Energy, Inc. ("Dominion"). The acquisition would be accomplished by merging SCE&G's parent company, SCANA Corp. ("SCANA") with and into Dominion, such that SCE&G would become an indirect subsidiary of Dominion.

I also have been asked to review the portion of the Application and associated testimony that seeks a Commission finding of prudency for the cancellation of the construction of two new nuclear power units at the V.C. Summer station. The Company refers to the Summer station expansion as the New Nuclear Development Project, which it abbreviates "NND Project." For consistency, I will use that same terminology.

Q. Why is AARP interested in this case?

A. I am advised that AARP has more than 625,000 members in South Carolina many of whom are electricity customers of SCE&G.

Q. **What are your qualifications to provide this testimony in this case?**

A. For the past 35 years, I have devoted my professional life to work involving the public utility industry. This is true for my work as an attorney, as well as my work as a consultant, expert witness, and author.

I have testified as an expert witness before utility commissions or courts in the District of Columbia; the province of Nova Scotia; and the states of Alaska, Arizona, California, Connecticut, Delaware, Illinois, Kentucky, Maine, Maryland, Massachusetts, Minnesota, Mississippi, New Hampshire, New Jersey, New York, North Dakota, Ohio, Pennsylvania, and West Virginia. I also have testified as an expert witness before various federal, state, and local legislative committees. I have served as a consultant to the staffs of four state utility commissions, as well as to several national utility trade associations, and state and local governments throughout the country.

Prior to establishing my own consulting and law practice, I was employed by the Pennsylvania Office of Consumer Advocate from 1983 through January 1994 in increasingly responsible positions. From 1990 until I left state government, I was one of two senior attorneys in that office. Among my other responsibilities in that position, I had a major role in setting its policy positions on water and electric matters. In addition, I was responsible for supervising the technical staff of the office. I also testified as an expert witness for that office on rate design and cost of service issues.

Throughout my career, I developed substantial expertise in matters relating to the economic regulation of public utilities. I have published articles, contributed to books, written speeches, and delivered numerous presentations, on both the national and state level, relating to regulatory issues. I have attended numerous continuing education courses involving the utility industry. I also have participated as a faculty member in utility-related educational programs for the Institute for Public Utilities at Michigan State University, the American Water Works Association, and the Pennsylvania Bar Institute.

Q. Have you appeared previously before this Commission?

A. No, this is my first appearance as a witness in South Carolina.

Q. Do you have any experience that is particularly relevant to the issues in this case?

A. Yes, I do. As either an attorney or expert witness, I have participated in proceedings throughout the United States involving more than two dozen proposed utility mergers, acquisitions, divestitures, or similar corporate restructurings.

In addition, during the first 7 or 8 years of my tenure with the Pennsylvania Office of Consumer Advocate, much of my time was devoted to litigation and policy matters involving construction, financing, and rate-setting for new nuclear power plants. My work during that time considered issues of prudence, need, excess capacity (whether a plant was fully used and useful), financing, and related policy matters. Those cases involved the construction of Limerick units 1 and 2, Beaver Valley unit 2, and Perry unit 1; the cancellation of Perry unit 2; the restart of Three Mile Island unit 1; and cost recovery associated with damaged Three Mile Island unit 2.

After starting my own consulting and legal practice in 1994, I also was involved in several formal and informal matters involving the Long Island Lighting Company's cancellation of the Shoreham nuclear project, and the utility's eventual sale of electric operations to a newly created government-owned utility, the Long Island Power Authority, and gas operations to an investor-owned utility.

Unfortunately, over the years, I also have been involved with utilities that are in financial distress (or claim to be), including those in Chapter 11 bankruptcy proceedings or threatening to initiate them.

I am using all of that experience, as well as decades of experience in hundreds of rate cases, to aid my review of the Company's circumstances and proposals in this case.

Q. Have you prepared an exhibit summarizing your experience?

A. Yes. My curriculum vitae is attached to my testimony as Appendix A.

Summary

Q. What is the primary focus of your direct testimony?

A. My review focuses on three primary matters raised in SCE&G's Application and direct testimony: (1) the appropriate policy response to the cancellation of a major utility construction project; (2) the prudency of SCE&G's cancellation of the NND Project in July 2017; and (3) the reasonableness of the proposed Customer Benefits Plan and associated ratemaking mechanisms that are an integral part of the proposed merger.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are summarized as follows:

- I recommend that the Commission apply well-established ratemaking principles, including the used and useful principle and prudency requirements, coupled with the need to achieve results within a "zone of reasonableness" for investors and consumers.

- I conclude that a reasonable utility in SCE&G's position would have cancelled the NND Project during 2013 or, at the latest, by mid-2014. Had SCE&G cancelled the NND Project by mid-2014, its investment in the project would have been about one-half of what it was when the NND Project was finally cancelled in July 2017.

- I conclude that the proposed Customer Benefits Plan and associated ratemaking mechanisms are steps in the right direction but would not result in just and reasonable rates for consumers. In its place, I recommend an approach that would more equitably share the costs of the failed NND Project among consumers, SCE&G investors, and Dominion.

Q. Are you responding directly to the testimony of any Company witnesses?

A. Yes. My testimony focuses on various portions of the direct testimony filed by Company witnesses Addison, Hubbard, Lapson, and Rooks.

Q. Do you have any other preliminary matters to address?

A. Yes. A portion of my testimony deals with regulatory policy issues. Given the nature of public utility regulation, much of the public policy in this field is contained in decisions by regulatory agencies and courts; or in statutes, ordinances, or regulations. I will be citing to these types of sources. This should not be taken as a legal opinion (though I am a regulatory attorney in Pennsylvania), but rather as sources supporting my expert opinion concerning appropriate public policy and regulatory practice.

Appropriate Regulatory Response to Plant Cancellation

Q. In your experience, what is the appropriate response of regulatory commissions to the cancellation of a major construction project that could affect the financial viability of a public utility?

A. In my experience, utility regulators have responded to major plant cancellations and the resulting financial distress by looking to established regulatory principles. Those principles include the "used and useful" principle that requires customers to receive an actual benefit as utility customers from a utility investment; the prudency principle that limits a utility's return of and on investment to the prudently incurred expenditures on a project; all coupled with a balancing of the risks and rewards undertaken by utility investors and the need to ensure that essential utility services remain available to the public.

Q. How do those principles work together in practice?

A. In practical terms, these principles are balanced to try to achieve rates that are fair to all customers (often termed "just and reasonable" rates) and returns on investment that fairly compensate the utility's investors for the risks they have undertaken. That fair compensation for risk, however, also means that when an investment fails investors need to bear that risk. In rate-setting, parties and regulators often refer to a "zone of reasonableness" meaning that there is no single result that is reasonable, but there may be a range of reasonable options. This means, of course, that some results may lie outside of the zone of reasonableness, such that they result in rates that are unjust or unreasonable or returns to investors that are not commensurate with the risks they have undertaken.

Thus, in general terms, regulators attempt to achieve a result that is in the amorphous "zone of reasonableness." If that cannot be done, then extremely difficult choices must be made. In those unusual circumstances, regulators may choose (I would suggest that they are required to choose) to protect utility consumers by ensuring that rates are just and reasonable. If that occurs, then investors attempt to protect their interests through the bankruptcy court or by liquidating their investments for significantly less than they paid for them.

Q. Are you familiar with some of the history of failed utility investments in nuclear power projects?

A. Yes. I will give just a few examples of substantial investor losses that resulted from failed nuclear construction projects. In 1983 the Washington Public Power System defaulted on more than $2 billion in bonds after it cancelled the construction of a multi-unit nuclear power station. It took years for the law suits to get resolved, ultimately resulting in investors losing nearly two-thirds of their investment.

One of the more infamous examples is General Public Utilities Corp. which owned the Three Mile Island nuclear station in Pennsylvania. Soon after unit 2 began operating in 1979, the unit failed, suffering the worst accident in U.S. nuclear history, and resulting in a near-total loss of the $800 million invested in the plant, as well as more than $1 billion in increased purchased power costs. Special ratemaking provisions were put in place to permit the operating utilities to cover enough of their costs to avoid bankruptcy, but investors suffered a significant loss of their investment. Ultimately, General Public Utilities was sold to FirstEnergy Corp., a utility holding company.

Another interesting case study is Long Island Lighting Company which owned the Shoreham unit that was cancelled after it conducted low-power testing, but before it entered commercial operation. Ultimately, the utility's $6 billion investment in the plant was partially recovered from a combination of increasing customers' rates (for many years after plant cancellation, Long Island had the highest rates in the continental United States), selling the electric utility to a public authority, and selling the gas utility to another investor-owned utility. Electric customers' rates increased significantly to bear some of the burden of the plant's cancellation.

Q. What lessons do you learn from these examples of failed utility investments?

A. These examples reinforce what I said earlier about the need for utility regulators to find solutions within the "zone of reasonableness" that protect consumers from paying unjust or unreasonable rates and still try to protect investors. When investments fail, there is no question that investors will lose a significant amount of their investment. But because utilities provide an essential public service, ratepayers may also suffer if they are required to pay higher rates to ensure the continued viability of the utility.

There is a limit, however, to how high those rates should go to prop up utility investors. The failures in Washington, Pennsylvania, and New York that I summarized all resulted in customers paying higher rates and investors suffering substantial losses of their investment. No one wins, but a reasonable result is reached that shares the burden of the failed investment.

Q. On pages 21-23 of his direct testimony, Dr. Hubbard discusses two decisions of the U.S. Supreme Court that he says provide the "appropriate legal framework and reasoning that underlie traditional rate-of-return regulation." Do you agree with his summary?

A. No, I do not. First, he errs on page 21, line 13, when he uses the disjunctive ("or") in describing the inter-relationship of prudency and the "used and useful" principle. Specifically, he states: "regulators allow the utility to collect a return on its investments that the regulators deem are 'prudently incurred' or are 'used and useful.'" In fact, traditional regulation requires investment to be <u>both</u> prudently incurred <u>and</u> used and useful.

Second, Dr. Hubbard inexplicably fails to discuss a third U.S. Supreme Court decision that establishes the framework for traditional utility regulation: *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989). Importantly, and the reason I am incredulous that Dr. Hubbard did not discuss it, that case involved costs associated with the cancellation of nuclear power plants by two utilities in Pennsylvania. David Barasch, the respondent before the Supreme Court, was the head of the office where I worked at that time, so I am very familiar with the case and its underlying facts.

Briefly, the U.S. Supreme Court unanimously upheld the Pennsylvania Supreme Court's decision that applied a statutory "used and useful" principle to disallow cancelled plant costs from the utility's rate base. In so doing, the Court emphasized that a constitutional taking of utility property would occur only if the net effect of a rate order were so low as to confiscate the utility's property. Specifically, the Court summarized the constitutional standard as follows:

> The guiding principle has been that the Constitution protects utilities from being limited to a charge for their property serving the public which is so "unjust" as to be confiscatory. *Covington & Lexington Turnpike Road Co. v. Sandford*, 164 U.S. 578, 597 (1896) (A rate is too low if it is "so unjust as to destroy the value of [the] property for all the purposes for which it was acquired," and in so doing "practically deprive[s] the owner of property without due process of law"); *FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 585 (1942) ("By long standing usage in the field of rate regulation, the 'lowest reasonable rate' is one which is not confiscatory in the constitutional sense"); *FPC v. Texaco Inc.*, 417 U.S. 380, 391-392 (1974) ("All that is protected against, in a constitutional sense, is that the rates fixed by the Commission be higher than a confiscatory level").

Id., 488 U.S. at 307-308.

The Supreme Court also specifically rejected an attempt to adopt the "prudent investment" test, or any other particular ratemaking methodology, as being constitutionally required. On this issue, the Court held:

> The adoption of a single theory of valuation as a constitutional requirement would be inconsistent with the view of the Constitution this Court has taken since *Hope Natural Gas, supra*. As demonstrated in *Wisconsin v. FPC*, circumstances may favor the use of one ratemaking procedure over another. The designation of a single theory of ratemaking as a constitutional requirement would unnecessarily foreclose alternatives which could benefit both consumers and investors. The Constitution within broad limits leaves the States free to decide what ratesetting methodology best meets their needs in balancing the interests of the utility and the public.

Id., 488 U.S. at 316 (footnote omitted).

Q. **How does the *Duquesne Light Co. v. Barasch* decision inform your judgment about an appropriate regulatory response to a cancelled construction project?**

A. The Supreme Court's decision gives States and utility commissions wide latitude to develop ratemaking mechanisms and approaches that best meet the needs of the particular circumstances they face. In the Pennsylvania case reviewed by the Court, the state legislature concluded that an appropriate result was to protect consumers from paying anything for plant investments that never provided service to the public. As I explained above, in other cases (even in Pennsylvania), the appropriate result was to have consumers pay some of the costs of investments that did not serve the public but require investors to bear a significant portion of the failure.

Prudency of SCE&G's Cancellation of the NND Project

Q. On page 48, lines 12-13, of his direct testimony, Mr. Addison states: "it would not have been prudent to abandon the [NND] Project at any time before July 31, 2017." Do you agree with this statement?

A. No, I do not. I conducted a review of some of the relevant documents and circumstances and I conclude that a prudent utility considering the information available at the time costs were incurred and decisions should have been made would have cancelled the NND Project during 2013 but certainly no later than mid-2014.

Q. What types of information did you rely on to determine what a prudent utility would have done in the period covering 2013 and the first half of 2014?

A. I relied primarily on two sources of information: (1) information published in the trade press during that time period concerning the NND Project, a similar project at the Vogtle plant in Georgia that was using the same technology (and many of the same vendors) as proposed for the NND Project, and other utilities' capacity-planning decisions; and (2) more than 300,000 pages of documents made public by SCE&G's co-owner in the NND Project, Santee Cooper.

Q. What facts from those sources have led you to the conclusion that a prudent utility would have cancelled the NND Project no later than mid-2014?

A. I base this conclusion on the following facts and observations.

First, prior to 2013, the NND Project experienced significant, costly delays. A May 6, 2014, letter from the CEOs of SCANA and Santee Cooper (attached hereto as Exhibit SJR-1) discusses some of these significant delays. According to the letter, as early as 2011, one of the critical contractors, Shaw Modular Solutions ("SMS"), was seriously behind schedule on the construction of critical components for the NND Project, particularly the auxiliary building and fuel handling area that sits next to the containment vessel, known as the "CA-20 module."

The CA-20 module originally was scheduled for completion in November 2011.[1] By June 2011, it was clear that SMS's deficiencies would make that date impossible to meet. SMS consistently failed to make deliveries promised leading up to and in June 2011. The Nuclear Regulatory Commission ("NRC") then found that SMS's quality assurance program was deficient.[2] This led to pushing out the NND Project's schedule by more than a year, with a new CA-20 completion date set for January 2013.[3]

"By July 7, 2012," the CEOs wrote, however, "only 21 of 72 CA-20 sub-modules had been delivered to the site."[4] By September 2012, according to the letter, "at least thirty of the milestone dates had already come and gone without completion of the associated milestone event. By that time, only 31 of the 72 sub-modules for CA-20 had been delivered to the site," even though the entire module was supposed to be complete in less than four months (January 19, 2013).[5]

In October 2012, the NRC conducted a follow-up inspection and again found that SMS had not come into compliance with safety and quality assurance requirements.[6]

[1] Exhibit SJR-1, p. 3.
[2] *Id.*
[3] *Id.*, p. 5.
[4] *Id.*, p. 4.
[5] *Id.*, p. 5.
[6] *Id.*, p. 6.

Indeed, around that time, the NRC warned that SMS employees were being punished for raising safety concerns.[7]

By this point (late 2012) it was clear that the January 19, 2013, date for completion of the module would not be met. Indeed, by March 2013 – two months after the entire module was supposed to be complete – "only 40 of the 72 sub-modules for CA-20 had been received."[8] That led to a further nine-month delay in the project schedule, with a targeted CA-20 completion date of October 31, 2013.[9]

Q. Did other important events for the NND Project occur prior to 2013?

A. Yes. Beginning in 2011 and continuing through 2012 and into 2013, Santee Cooper (which owns 45% of the NND Project) tried to sell more than half of its interest in the Project. It contacted numerous other utilities and could not find a buyer. That is, it was unable to find another utility that was willing to assume the risk of even a small portion of the Project. Ultimately in January 2014, it was able to sell just a 5% interest in the Project back to SCE&G (which already owned 55% of the NND Project), but SCE&G only agreed to buy it upon completion and commercial operation of the Project. That is, even SCE&G was unwilling to commit to any more construction risk for the NND Project.

This may be the most compelling evidence of what a prudent utility would do at the time. Numerous other utilities in the same region of the country, with the same general knowledge of power markets, fuel prices, and construction costs were given an

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[7] *Id.*
[8] *Id.*
[9] *Id.*, p. 7.

opportunity to invest in the NND Project and declined to invest anything in it. That should have provided a clear indication to a prudent utility that the Project was not economical and that it was not prudent to invest any more capital on it.

Q. When it was trying to sell a portion of the NND Project, did Santee Cooper conduct any analyses to convince potential buyers that the NND Project was a good investment?

A. Yes. In developing its efforts to try to sell a portion of the NND Project, Santee Cooper retained an outside consultant to evaluate the potential risks, costs, and benefits of ownership, and to help make the case to a prospective purchaser. That consultant, Howard Axelrod, had consulted with Santee Cooper for many years, including at the very start of the NND Project in 2005.[10]

On March 11, 2013, Dr. Axelrod drafted a memorandum to Santee Cooper that summarized Santee Cooper's attempts to divest a portion of the Project.[11] He summarizes: "While several entities contacted indicated an interest to further pursue its investigation of the VCS [V.C. Summer] offering, to date, only Duke Energy is in active negotiations with Santee Cooper with regards to the direct sale of VCS 2 & 3 assets. No other utility that was approached by Santee Cooper has indicated an interest in either an outright asset purchase or the execution of a long term PPA [power purchase agreement]."[12]

[10] *See* South Carolina Public Service Authority Generation Resource Plan 2005.
[11] Memorandum from Howard Axelrod of Energy Strategies Inc. to Sylleste Davis of Santee Cooper, Summary Report on Energy Strategy's VCS Marketing Activities (Mar. 11, 2013), a copy of which is attached hereto as Exhibit SJR-2.
[12] *Id.*, pp. 2-3.

Dr. Axelrod then concluded that "until VCS construction is complete, both plants are operational, and all costs are known with a high degree of certainty, it is unlikely that any utility, albeit with few exceptions, would likely entertain such an asset acquisition unless the offering was significantly discounted to reflect the risks and uncertainties associated with a $10 billion ongoing project."[13] The exceptions listed in the footnote were Duke and TVA. TVA already had rejected any attempt to buy into the NND Project and Duke withdrew from negotiations in early 2014.

Dr. Axelrod explained the reasons for his conclusion, writing: "annual revenue requirements for VCS as measured by its unit costs will be higher than currently available alternative sources of generation including a new combined cycle gas turbine. In order for Santee to offer a competitively priced PPA for VCS would require, for a period of time, a measurable 'discount' relative to VCS's embedded costs. Depending upon the forecasted assumptions, <u>it could take over ten years before VCS's annualized costs are below competitive prices in the Southeast</u>."[14]

The memorandum continued to explain the economics of the NND Project as compared to a reasonably available alternative, combined cycle gas turbines ("CCGT") fueled by natural gas. Dr. Axelrod stated that "<u>there is a definite economic advantage to CCGT over nuclear measured in both annual levelized unit costs and net present value (NPPV) of life cycle revenue requirements</u>. The capital cost of the CCGT is a quarter of a nuclear plant, the time to plan through construction is also one quarter, and a reasonably economical size can be as low as 300 MW to better match load growth. My study shows

[13] *Id.*, p. 2 (footnote omitted).
[14] *Id.*, pp. 2-3 (emphasis added).

that under these conditions, there is an 80%+ chance that even under a range of conditions the NPPV of a CCGT will be less than that of a new nuclear plant."[15]

The memorandum also contains notes of Dr. Axelrod's interviews with executives from several utilities that had declined to purchase a share of the NND Project. The notes summarize other utilities' positions and concerns, including the following:

- One utility evaluated nuclear but "was concerned over capital intensity and impact on balance sheet." Instead it will build or buy CCGT capacity.[16]
- A sale to a utility in the PJM Interconnection would be impractical because "peak hour clearing prices averaged below $60/MWH" in November and August. "Off peak prices averaged below $30/MWH."[17]
- Another utility said the price "was just too high."[18]

The memorandum also emphasizes that even if the NND Project and a new CCGT were economically equivalent (which they were not), "the profits from a nuclear plant would be between 5 to 8 times greater than that of a CCGT" because of the capital intensity of a new nuclear plant. Dr. Axelrod thought this could "offer sizable contributions to earnings for an investor-owned utility."[19]

Two weeks later, on March 23, 2013, Dr. Axelrod produced a slightly revised version of the memorandum, now in report form.[20] The revised version adds a new piece of information: "Projected regional forward peak load prices remain at or below

[15] *Id.*, p. 5 (emphases added).
[16] *Id.*, p. 11.
[17] *Id.*, p. 12.
[18] *Id.*, p. 14.
[19] *Id.*, p. 3.
[20] Howard Axelrod, The V.C. Summer Strategic Marketing Plan: Summary Report (Mar. 23, 2013), attached hereto as Exhibit SJR-3.

$50/MWh through the end of the decade, which is significantly less than the embedded cost of a new nuclear plant estimated at over $100/MWh."[21]

Q. What do you conclude about the March 2013 analyses prepared for Santee Cooper?

A. There is no question that in March 2013, and the months leading up to that point, numerous utilities had rejected the NND Project because it was not economically viable or not consistent with their provision of low-cost service to customers. While Dr. Axelrod tweaked various assumptions to try to show that nuclear power could be cost-competitive with natural gas, Santee Cooper did not find any utilities that agreed. Faced with this information in March 2013 (when the NND Project was less than 50% complete), coupled with the significant construction delays and deficiencies that still had not been remedied, it is my opinion that a prudent utility would have declined to spend more money on the Project.

Indeed, as Dr. Axelrod stated, power prices during peak demand periods were expected to be $50 per MWh or less through 2020, while the NND Project (assuming no more cost over-runs or significant delays) would cost on the order of $100 per MWh. Several other utilities in the region rejected the NND Project because it was not a prudent investment for them. SCE&G should have acted prudently and done the same in March 2013.

[21] *Id.*, p. 4 (page number refers to the Exhibit page number which numbers the cover as page 1).

Q. Was there other information available in March 2013 about the relative costs of the NND Project and natural gas CCGT?

A. Yes. According to a report published in the trade press, Vermont Law School's Institute for Energy and the Environment released a study on March 14, 2013, that reached essentially the same conclusions as Dr. Axelrod's study for Santee Cooper. The Vermont report concluded that the cost of electricity from new CCGT would be "cheaper than the new reactors [at V.C. Summer] by $9.4 billion over a 40-year period."[22] The article notes that, as of the end of 2012, the sunk cost for the NND Project was $1.9 billion. This report provides a further indication, from a different analyst, that the NND Project was not economically competitive in early 2013.

Q. Did anything else occur in March 2013 timeframe that would have led a prudent utility to cancel the NND Project?

A. Yes. As I mentioned earlier, a similar project was under construction in Georgia at the Vogtle nuclear plant. Many of the same contractors were working on both projects, the same reactor technology was being used, and unfortunately many of the same construction problems were being experienced. On February 28, 2013, Georgia Power announced that its 45.7% share of the Vogtle project cost would increase by $381 million, from $4.4 billion to $4.8 billion, implying a total project cost of $10.5 billion for a similar two-unit project.[23] The increased cost was the result of a nearly two-year delay in the estimated completion date for the project.

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[22] Matthew Bandyk, Study: New nuclear power projects are uneconomic 'sunk costs', *SNL Power Daily with Market Report* (Mar. 15, 2013), attached hereto as Exhibit SJR-4.
[23] Shelly Sigo, Moody's: Vogtle Nuclear Plant Cost Hikes, Delays are Negative, *The Bond Buyer* (Mar. 14, 2013), attached hereto as Exhibit SJR-5.

At the end of March 2013, Moody's issued a report for the Municipal Electric Authority of Georgia ("MEAG"), a 22.7% owner of the Vogtle project. According to a report in the financial press, the Moody's analyst stated that "uncertainties on the ultimate cost and construction schedule of Vogtle nuclear units 3 and 4 give pause as to whether the project will face more serious credit challenges." He also is quoted as saying that "further delays and new cost over-runs are likely, and there is a finite level that will be tolerated by ratepayers."[24]

Q. Did anything happen during the second and third quarters of 2013 that would have led a prudent utility to re-evaluate the continued construction of the NND Project, even if activities up to that time had not led it to cancel the Project?

A. Yes. Turning back to the May 6, 2014, letter from the CEOs (Exhibit SJR-1), critical construction delays continued to occur throughout 2013. According to that letter, by May 2013, "only 41 of the 72 CA-20 sub-modules had been delivered."[25] Moreover, there was a period of 11 weeks – 2-1/2 months – when only one module was delivered to the project site.

On June 5, 2013, SCE&G announced that construction problems had delayed the in-service date of unit 2 by at least a year, increasing costs for SCE&G's 55% share by an estimated $200 million.[26] Following the announcement, Moody's reported that the news

[24] Shelly Sigo, MEAG Ratings Could be Pressured by Nuke Plant Cost, Delays: Moody's, *The Bond Buyer* (Mar. 27, 2013), attached hereto as Exhibit SJR-6.
[25] Exhibit SJR-1, p. 7.
[26] Andrew Engblom, SCE&G says construction issues likely to delay new V.C. Summer nuke, add costs, *SNL Energy Finance Daily* (June 6, 2013), attached hereto as Exhibit SJR-7.

was "credit negative" for SCANA, SCE&G and Santee Cooper, noting that total project costs could increase by $365 million.[27]

A month later, in July 2013, Santee Cooper was trying to raise an additional $1.75 billion to help fund NND Project construction and to refinance older debt. According to a front-page story in the Charleston *Post & Courier* on July 23, 2013, Standard & Poor's was concerned about Santee Cooper's ability to sell a substantial part of its interest in the NND Project, noting that if it couldn't, "Santee Cooper ... would be saddled with excess power and higher debt repayment costs." Moody's noted that even after this debt issuance, "Santee Cooper will still need to raise another $2.8 billion to pay for its $5.1 billion share" of the Project.[28]

On August 1, SCE&G announced that contractor delays also would push back the in-service date for unit 3 by a year or more.[29]

Santee Cooper's consultant, Dr. Axelrod, produced another study on August 19, 2013.[30] While that study (as did his others) tries to paint a rosy picture for the future of nuclear power, his actual findings are quite telling and should have led a reasonable and prudent utility to abandon construction of the NND Project. Specifically, Dr. Axelrod concluded that even with a projection of significantly increasing natural gas prices, the levelized cost of a new advanced CCGT averaged $65.6 per MWh, while the likely

[27] Amy Poszywak, Moody's: Construction delay at Summer nuke is credit negative for SCANA, Santee Cooper, *SNL Energy Finance Daily* (June 11, 2013), attached hereto as Exhibit SJR-8.
[28] Santee Cooper's costs raising alarms $5.1 B nuclear plant obligations worry credit rating firms as utility prepares to offer $1.75B in bonds, *Post & Courier* (Charleston, SC) (July 23, 2013), attached hereto as Exhibit SJR-9.
[29] Amy Poszywak, SCANA revises CapEx plans to reflect VC Summer delays, *SNL Energy Finance Daily* (Aug. 2, 2013), attached hereto as Exhibit SJR-10.
[30] Howard Axelrod, A Case Study of Economic Cost and Risks Associated with Advance Nuclear Generation and Combined Cycle Gas Turbines (Aug. 19, 2013), attached hereto as Exhibit SJR-11.

levelized cost for an advanced nuclear plant like the NND Project was nearly double at $108.4 per MWh.[31] This confirms Dr. Axelrod's findings in March 2013 that a new nuclear plant would be about twice as expensive as a natural gas CCGT.

Further, he found that under expected conditions, there was less than a 12% chance that nuclear would end up saving consumers money as compared to CCGT. Moreover, the likely savings from CCGT averaged more than $1 billion (and in some cases rose to as much as $7 billion), while the most beneficial case for nuclear (less than a 1% chance of occurring) would save consumers less than $0.3 billion over its life compared to CCGT.[32]

Importantly, Dr. Axelrod's August 2013 analysis also found that even under "highly favorable conditions, annual costs for nuclear will likely exceed CCGT costs for a number of years. While consumers may benefit from nuclear over time, <u>the crossover point [the point where nuclear becomes less expensive than CCGT] could be anywhere from 15 to 30 years. The point of payback [the point where there is a cumulative net benefit from nuclear] could range from 35-50 more years.</u>"[33] In other words, under the most favorable assumptions for the NND Project, consumers would be worse off each year for at least the next 15 to 30 years and would be worse off cumulatively for between 35 and 50 years. And that is the <u>best case</u> he could come up with for the NND Project versus CCGT.

[31] *Id*, p. 5.
[32] *Id.*, p. 9.
[33] *Id.*, p. 20 (emphasis added).

As if that weren't enough to force any prudent utility to cancel the NND Project, Dr. Axelrod also warned of the risks of additional construction cost increases. He wrote that there are "inherent pre-operational risks associated with schedule and construction costs. Delays at Vogtle have already incurred ~$700 million in added costs."[34]

Q. Did Santee Cooper do anything after Dr. Axelrod prepared this report?

A. I don't know if it was directly related to Dr. Axelrod's report, but on August 23, 2013, the President and CEO of Santee Cooper sent a letter to the Chairman and CEO of SCE&G, attached as Exhibit SJR-12. In that letter, Santee Cooper outlined the cause of the significant construction delays, exhibited concerns about the contractors responsible, and concluded that the construction consortium's "inability to fulfill their contractual commitments in a timely manner places the project's future in danger."

Q. Did anything occur in the remainder of 2013 to change your conclusion that a prudent utility would have cancelled the NND Project?

A. No. During the last four months of 2013, the NND Project continued to experience significant delays, increased costs, and contractor non-performance. Going back to the May 2014 letter that summarized the poor construction history of the auxiliary building and fuel loading module (CA-20), the CEOs wrote that on September 18, 2013, it became clear that the October 31 completion date for CA-20 would not occur. So a new target date of January 24, 2014, was established.[35] The contractor promised that all CA-20 sub-

[34] *Id.*, p. 24.
[35] Exhibit SJR-1, p. 8.

modules would be on-site by November 4, which would leave almost three months for quality assurance and assembly.[36]

Unfortunately, the contractor again failed to meet its promised delivery date. All 72 sub-modules of CA-20 were finally on-site by December 4, but according to the CEOs' letter, "30 of them required documentation processing and repairs .... The modification effort continued well into 2014."[37]

Incredibly, the CA-20 work continued to slip during the first quarter of 2014. The CEOs summarized this as follows:

> The Consortium has been providing our construction team with daily email updates relating to CA-20, but the updates continue to illustrate performance shortcomings. The March 11, 2014 email update reflected an on-hook date of March 31. The email updates of March 12 and 13 reflected the same date but stated that such date was "in jeopardy" and pending management review. The March 14, 15, 17 and 18 email updates all reflected a date of April 7 for this activity. Those from March 20, 21, 22, 23, 25, 26 and 27 all stated that the April 7 date was "under review." Beginning on March 28, the email updates stated that the on-hook date had slipped again to May 10. In short, the projected on-hook date for CA-20 continues to slip and, by the end of March, we were farther away from completion of that activity than the Consortium had stated we were at the beginning of March.[38]

Q. Were the delays in the CA-20 module the only significant construction delays that occurred during 2011 through mid-2014?

A. No. The letter in Exhibit SJR-1 identifies lengthy delays with other critical components. For example, the steam generator and refueling canal module (the CA-01 module) also was seriously behind schedule. The CA-01 module originally was scheduled to be

[36] *Id.*
[37] *Id.*, p. 10.
[38] *Id.*, p. 10 (emphasis added).

complete on March 29, 2012.[39] As of May 2014, completion was scheduled for August 31, 2014, a delay of almost 2-1/2 years.[40]

Q. What do you conclude about the prudency of SCE&G's actions during 2013 and 2014?

A. I conclude that a prudent utility considering the information available during 2013, and certainly by the end of the second quarter of 2014, would have concluded that the NND Project was not economical, that completion of the NND Project would be detrimental to the utility's consumers, and that it was extremely likely that the NND Project would take longer to complete and be much more costly to complete than the then-current estimates. Faced with all of this information, including the failure of critically important contractors to perform their work in a timely fashion, a prudent utility would have cancelled the NND Project no later than June 30, 2014.

Q. Approximately how much had SCE&G invested in the NND Project as of June 30, 2014?

A. According to SCANA's filings with the Securities and Exchange Commission, SCE&G had invested \$2.7 billion in the NND Project as of December 31, 2014, and \$2.3 billion as of December 31, 2013.[41] I estimate, therefore, that SCE&G had invested approximately \$2.5 billion in the NND Project as of June 30, 2014.

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[39] *Id.*, p. 3.
[40] *Id.*, p. 10.
[41] SCANA Corp. 10-K filing with the S.E.C. for the year ending 12/31/2014 (filed Feb. 28, 2015), p. 24; SCANA Corp. 10-K filing with the S.E.C. for the year ending 12/31/2013 (filed Feb. 28, 2014), p. 56.

Q. How does that compare to the amount the Company had invested as of July 31, 2017, when it finally cancelled the NND Project?

A. The following figures are taken from SCANA's quarterly report for the period ending June 30, 2018.[42] SCE&G wrote off $1.118 billion of NND Project costs during 2017. As of December 31, 2017, SCE&G reported that its remaining investment in the NND Project was $3.976 billion, meaning that upon cancellation it had invested approximately $5.1 billion in the NND Project. This means that in the three years between June 30, 2014, and July 31, 2017, the Company doubled its investment in the NND Project – increasing its investment from $2.5 billion to $5.1 billion.

Review of the Proposed Customer Benefits Plan

Q. Have you reviewed the Company's proposed Customer Benefits Plan?

A. Yes.

Q. Please summarize your understanding of that plan.

A. As I understand it, the major elements of the Customer Benefits Plan are the following:

- SCE&G would make a one-time payment to customers of $1.3 billion within 90 days of the merger closing presumably to reflect benefits of the merger (since that element is missing from the plan if the merger does not occur).
- Customers would receive a refund of $575 million of payments made under the Base Load Review Act ("BLRA"), amortized over 8 years.
- Customers would pay $3.3 billion in remaining NND Project costs amortized over 20 years.

[42] SCANA Corp. 10-Q filing for the quarter ending June 30, 2018 (dated Aug. 2, 2018), pp. 23 and 42-45. While it is almost 100 pages long, I believe it is important for the Commission to have the most recent statement of SCE&G's financial condition in the record, so I am attaching the entire 10-Q filing as Exhibit SJR-13.

- The Company would not seek to include in rates the $180 million purchase price of a 540 MW CCGT that it purchased to replace some of the NND Project's capacity.
- Various other rate adjustments would be made for tax effects.

Q. What is your understanding of the net effect on customers from the Company's proposal?

A. In assessing the effect on SCE&G's customers, I begin with what customers already have paid under the BLRA surcharges for a plant that will never provide them with a single watt-hour of electricity. According to the SCANA quarterly report for June 30, 2018, as of that date customers already have paid SCE&G $2.1 billion under the BLRA.[43] Approximately $109 million of that is subject to refund because of the legislatively mandated rate reduction as of April 1, 2018, in Act 258.[44] Moreover, customers are continuing to pay an additional $166 million each year, even after the reduction mandated in Act 258. In other words, by year-end 2018, customers will have paid approximately $2.2 billion for the NND Project.

The Customer Benefits Plan would refund $575 million of that amount over 8 years. That would leave customers already having paid approximately $1.5 billion for the NND Project.

Then the Customer Benefits Plan would require customers to pay an additional $3.3 billion plus carrying charges for the remaining investment in the plant. Company witness Rooks states that this amount will be recovered from customers through a Capital Cost Rider Component that would be "set to recover approximately $330 million" in the

[43] *Id.*, p. 44.
[44] *Id.*, pp. 42-43 (the $109 million represents the difference between revenues collected and revenues authorized under Act 258 from April 1 through June 30, 2018).

first year. Rooks PFT p. 5. The Capital Cost Rider Component would be reduced each year as the $3.3 billion is amortized.

Q. Is the Company proposing to earn a return on the $3.3 billion being amortized?

A. I do not know for certain, but it appears that the Company has either used an explicit rate of return or a front-loaded amortization method that significantly increases costs to consumers in the early years. The Company does not state the rate of return it used in its calculations or how much revenue collections would decline each year. If the $3.3 billion were being paid by customers over 20 years with no return and no front-loading, however, the first-year amount would be $165 million, not the $330 million stated by Mr. Rooks.

Q. Can you estimate how much customers would pay for the NND Project under the Company's plan?

A. I estimate that after considering all of the refunds and new charges, as well as the amounts already paid, customers would end up paying at least $4.5 billion in higher rates for a project that was never completed and never provided customers with service.

Q. In your opinion, would the Company's Customer Benefits Plan represent a reasonable sharing of the burden of a failed plant investment?

A. No. A strict application of the "used and useful" principle would have customers pay nothing for a failed plant investment. As I discussed above, if the Company had prudently cancelled the NND Project in mid-2014, its total investment would have been $2.5 billion. Thus, if the Commission is looking to achieve some type of reasonable sharing between customers and investors, the Company's plan does not achieve this. The

Company spent $5.1 billion on the failed project. It received $1.1 billion in a settlement from Toshiba, leaving a remaining balance of $4.0 billion. It is grossly unreasonable to require customers to pay $4.5 billion or more for that investment.

Q. What do you recommend?

A. I recommend that the Commission should end the BLRA surcharge on December 31, 2018, and that the Company should not be required to refund the $109 million collected between April 1 and June 30, 2018. This would result in customers paying approximately $2.2 billion for the failed NND Project. I calculate this by taking the amount paid through June 30, 2018, as reported by the Company, of $2.1 billion, and adding six months of reduced BLRA payments, which the Company estimates would be $166 million annually, or approximately $83 million from July 1 through December 31. That brings the total amount paid by customers to approximately $2.2 billion.

I further recommend that there should be no further recovery of NND Project costs from customers, and neither should there be any refunds of amounts paid. The customers' contribution to the failed project, therefore, would be $2.2 billion.

Q. What would that mean for the Company's investors?

A. According to the Company's June 30 quarterly report, the Company also has written off $1.118 billion in plant value, which after taxes cost investors $690 million.[45] There remains on the books a regulatory asset of approximately $4.1 billion offset by a regulatory liability of $1.1 billion for the Toshiba settlement proceedings, for a net investment of $3.0 billion. If the Company wrote off that entire investment, I would

[45] *Id.*, p. 44.

estimate that the after-tax cost would be on the order of $2.0 billion to $2.2 billion, taking into account the lower federal income tax rate that is now in effect.

Q. Can SCANA's stockholders absorb a $2 billion write-down to common equity?

A. Yes, it appears that they can. At June 30, 2018, SCANA's balance sheet shows a common equity balance of $5.337 billion and long-term debt of $6.098 billion.[46] If the common equity balance were written down by $2.0 billion to $3.3 billion (as an example), that would result in a common equity ratio of approximately 35%. According to Company witness Lapson, the Company's debt covenants require at least a 30% equity ratio. Lapson PFT p. 23.

Q. Please summarize your rate recommendations.

A. I summarize my rate recommendations as follows:

- End the BLRA surcharge on December 31, 2018.
- Do not provide customers with any refund of amounts paid through that date under the BLRA.
- Do not require customers to pay any additional amounts in rates after December 31, 2018, to support the failed investment in the NND Project.

Q. Do you have a position on the remaining element of the Company's proposed Customer Benefits Plan, the $1.3 billion one-time payment within 90 days after the merger closes?

A. First, I do not take a position on the merger between Dominion and SCE&G. I have not been able to analyze the transaction in any detail and I would not want to foreclose any parties who may have concerns with that proposed transaction. If the transaction is

[46] *Id.*, p. 8.

approved and closes, though, I would expect there to be substantial synergy savings achievable through the eventual consolidation of back-office operations and other efficiencies, as utilities have claimed in many other merger transactions. I do not know if $1.3 billion is the appropriate level of compensation for those savings, but there should be some substantial amount provided to consumers to provide a tangible benefit from the transaction.

Q. Does the benefit need to be provided in a one-time check to each customer?

A. No. That seems to be a public relations gimmick designed to win popular support for the merger. I am not opposed to a one-time payment by check, but it seems to be a costly way to provide a tangible benefit to consumers. A comparable benefit could be provided to consumers at much lower cost through a bill credit, either one-time or spread over a period of 12 to 36 months.

Q. Do you have a specific recommendation for a bill credit, if the Commission decides to implement that approach?

A. Yes. At its final level before Act 258 was passed, the BLRA surcharge was approximately 18% and provided SCE&G with approximately $445 million per year in revenues.[47] If a similar bill credit were provided for 36 months that would provide customers with savings of approximately $1.3 billion over three years. That would avoid the administrative burden of mailing hundreds of thousands of checks, it would ensure that customers receive benefits roughly in proportion to the size of their electric bills, and it would give Dominion and SCANA the opportunity to realize some of the savings they hope to achieve from the merger.

[47] *Id.*, p. 44.

Conclusion

Q. Please summarize your conclusions and recommendations.

A. I conclude that a prudent utility would have cancelled the NND Project no later than June 2014. At that time, the plant investment was approximately $2.5 billion.

I recommend that a reasonable sharing of the burden of the failed investment in the NND Project, considering the prudency of the Company's decision-making, and the legal environment when it made its investment decisions, would be to continue the BLRA surcharge at its reduced level through December 31, 2018. After that date, the surcharge would end and customers would not pay anything further to support the failed investment. I also recommend that there should be no refunds of any amounts paid under the BLRA. This would result in customers paying approximately $2.2 billion to support the NND Project that will never be completed or provide the public with service.

Finally, I recommend that if the merger between SCANA and Dominion is approved and closes, that Dominion should provide SCE&G customers with checks or bill credits totaling at least $1.3 billion, as SCE&G and Dominion have proposed.

Q. Does this conclude your direct testimony?

A. Yes, it does.